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President and CEO

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

September 2, 2003

The Honorable John Dingell
U.S. House of Representatives
Committee on Energy and Commerce
Washington, D.C. 20515-6115

Dear Congressman Dingell:

The North American Electric Reliability Council (“NERC”) is pleased to provide responses to the questions you posed on August 22, 2003, concerning the August 14th blackout in the upper Midwest and Northeast United States and eastern Canada.

Question 1: In your testimony before the Subcommittee on Energy and air quality on March 13, 2003, you state the following:

NERC’s rules, which are not now enforceable, have generally been followed, but that is starting to change. As economic and political pressures on electricity suppliers increase and as the vertically integrated companies are being disaggregated, NERC is seeing an increase in the number and severity of rules violations.

- a. Could you expand on this statement by providing specific examples of such violations?**
- b. Without citing any company by name, are any of these companies located in the regions affected by last month’s blackout?**
- c. To your knowledge did any of these rules violations play a part in the blackout?**

Since the inception of the North American Electric Reliability Council in 1968, compliance with its reliability standards has been voluntary. While NERC monitors the utilities for compliance with certain operating and planning standards, it has no means to enforce compliance with those standards.

For many years, NERC has monitored compliance with those operating standards that require minute-to-minute generation and demand balancing within each of about 140 control areas. NERC has also conducted reliability assessments each year that assess the generation and transmission expansion plans within each Regional Reliability Council against that Council’s own reliability standards. NERC also analyzes system disturbances and unusual occurrences for “lessons learned,” which helps us improve our reliability standards, reliability assessment procedures, operator training, and operating procedures.

In 1999, the NERC Board of Trustees implemented a Compliance Enforcement Program (CEP) to establish a more systematic review of compliance with NERC and regional reliability standards, and to expand the number of reliability standards that NERC monitors for compliance. While NERC cannot assess penalties and sanctions for non-compliance, we do calculate simulated penalties that would have been assessed under a system of mandatory compliance. The CEP also provides actual compliance statistics for several of NERC’s reliability standards that we have never before been able to track.

NERC reviewed 27 compliance measures in 2002, including 10 from our planning standards and 17 from our operating policies. The CEP found that the Regional Councils and their members are about 94% in compliance with these measures. The 6% non-compliance represents 97 planning standards violations and 444 operating policy violations, with simulated penalties of just over \$9 million. Specific examples of compliance violations in 2002 included the following (taken from NERC 2002 Compliance Enforcement Program Report, May 7, 2003; revised June 11, 2003):

- **Operating portions of the transmission system beyond their “first contingency” rating.** NERC’s planning standards and operating policies require that the transmission system be planned and operated to withstand the failure of any single element without affecting other portions of the transmission system. Some control areas reported specific situations during which they operated beyond the first contingency rating of a portion of their transmission system. NERC refers to this rating as the “Interconnected Reliability Limit,” and violating this limit increases the possibility that a disturbance to the transmission system could result in a widespread cascading failure.
- **Exceeding control performance limits.** NERC operating policies require that each control area maintain a constant balance between its generation and demand within specified limits, recognizing that customer demand is constantly changing and generation control is never perfect. Operating outside those limits is considered a violation of these control performance policies and places a burden on the entire Interconnection as it feeds power to, or absorbs power from, the non-compliant control area. NERC expects control areas to comply with these control performance policies at all times, even when generation is limited. That expectation might require a control area curtailing customer demand through public requests for conservation, voltage reductions, and even load shedding. NERC performs monthly surveys that track each control area’s compliance with NERC’s control performance policies. Although most control areas fully comply with these policies, we have seen obvious instances of non-compliance that resulted in noticeably lower frequency in the Interconnection.
- **Failure to return generation-demand balance within 15 minutes following the sudden failure of generation.** Generating unit failures cause an instant imbalance between a control area’s generation and its customer demand. NERC’s control performance operating policies require that a control area return to a balance between its generation and customer demand within 15 minutes following the sudden generating unit failure. Many control areas pool their generation reserve in a reserve-sharing group to quickly restore this balance. Until that balance is achieved, the entire interconnection feeds power to the deficient control area. Our monthly surveys show that most control areas comply with this policy. Those that do not are required to carry additional operating reserves.
- **Lack of NERC-certified system operators.** Since January 1, 2001, NERC has required that all control center operators be NERC-certified. NERC certification requires that the system operators pass an examination based on our operating policies as well as a general knowledge of interconnected system operations. Just over 5,000 system operators are NERC-certified. Our 2002 compliance surveys found 193 instances where control areas did not have certified system operators on duty.
- **Lack of restoration plan training documentation.** NERC requires that utilities document that operators have received training in system restoration procedures, and we found 27 instances in 2002 where that documentation was lacking.

- **Non-compliance with regional underfrequency load shedding programs.** Underfrequency load shedding systems help provide a quick generation-demand rebalance when a portion of the Interconnection becomes isolated from the rest of the system. This underfrequency load shedding is accomplished automatically in fractions of a second. Each of the Regional Councils has established underfrequency load shedding requirements for its control area members. Not complying with these standards can result in insufficient underfrequency load shedding, or load shedding that doesn't occur until the frequency has declined too far. NERC found 44 cases of non-compliance with this planning standard in 2002.
- **Lack of system studies.** NERC planning standards require that utilities model their systems under normal, single contingency, and severe contingency situations. Studying the effects of contingencies on transmission system models helps the utilities and reliability coordinators understand how those systems are likely to respond under a range of normal to stressful situations. Lacking those studies means that the system operators may be faced with events whose outcomes might be unknown, i.e., operating in an unstudied state. Eighteen cases of non-compliance were reported in 2002.

Some of these instances of non-compliance occurred in the three Regional Reliability Councils affected by the August 14th outage, but the report does not identify particular entities. The investigation of the August 14th outage is ongoing, and it is premature to decide whether rules violations of the type indicated here might have played a role in the blackout.

Question 2: A widely-reported analysis of the blackout sequence of events, performed by the International Transmission Company (ITC), indicates that transmission lines and one generating unit in the northern Ohio service territory of FirstEnergy Corp. went out of service from approximately 2:00 p.m. until 4:06 p.m., when ITC noticed a reversal of 200 MW of power flowing from Ohio to Michigan. According to ITC, before this reversal occurred no one from the FirstEnergy Corporation notified ITC of service disruptions on its system that could affect ITC's system.

- a. Are there NERC and/or East Central Area Reliability Council (ECAR) protocols in place that govern a situation in which a utility should notify a neighboring utility that it is experiencing service problems that could affect the neighbor?**
- b. If yes, could you please cite the specific guideline or protocol.**
- c. If not, why aren't such protocols in place?**

NERC's operating policies include a number of requirements for information sharing and notification. Specifically, the introduction to Operating Policy 5, "Emergency Operations," Section A, "Coordination with Other Systems," states:

"A system, control area, or pool that is experiencing or anticipating an operating emergency shall communicate its current and future status to neighboring systems, control areas, or pools and throughout the interconnection. Systems able to provide emergency assistance shall make known their capabilities."

The policy then lists the following specific requirements:

1. **Notifying other systems.** A system shall inform other systems in their Region or subregion, through predetermined communication paths, whenever the following situations are anticipated or arise:
 - 1.1. **System is burdening others.** The system's condition is burdening other systems or reducing the reliability of the Interconnection.
 - 1.2. **Insufficient resources.** The system is unable to purchase capacity to meet its demand and reserve requirements on a day-ahead basis or at the start of any hour.
 - 1.3. **Lack of single contingency coverage.** The system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection.
 - 1.4. **Emergency actions for inability to purchase capacity.** The system anticipates 3% or greater voltage reduction or public appeals because of an inability to purchase emergency capacity.
 - 1.5. **Emergency actions for other reasons.** The system has instituted 3% or greater voltage reduction, public appeals for demand reduction, or load shedding for other than local problems.
 - 1.6. **Sabotage incident.** The system suspects or has identified a multi-site sabotage occurrence, or single-site sabotage of a critical facility.
2. **Hotline use.** When a condition is identified that could threaten the reliability of the Interconnection or when firm load shedding is anticipated, the affected CONTROL AREA, via their RELIABILITY COORDINATOR, shall utilize the Interconnection-wide telecommunications network in accordance with Appendix 7A — Regional and Interregional Telecommunication, Subsection A, "NERC Hotline," to convey that information to others in the Interconnection.

ECAR has informed NERC that the ECAR member companies observe NERC Policy 5 and do not have a duplicative ECAR document.

Question 3: Both International Transmission Company and FirstEnergy Corp. are participating members in the Midwest Independent System Operator (MISO). The homepage for MISO states, among other things, that "The Midwest ISO's role is to ensure equal access to the transmission system and to maintain or improve electric system reliability in the Midwest." The homepage goes on to state, in the section entitled "Security Coordination," that "Computer systems will continually analyze forecasted and actual system conditions. An extensive voice and data communications network will enable constant communications between the Midwest ISO, its members and neighboring regions."

- a. **What role does Midwest ISO have in monitoring events occurring in each of its members' respective service territories?**
- b. **What are the responsibilities that Midwest ISO has to inform member organizations that service problems in one territory could affect another?**
- c. **Based on your investigation to date, what actions did Midwest ISO take to attempt to avert the blackout crisis?**

As a NERC-certified reliability coordinator, Midwest ISO's role and responsibilities related to monitoring events within its reliability area are defined in NERC Policy 9, "Reliability Coordinator Procedures," Attachment A to these responses. These procedures include:

- Planning for next-day operations, including reliability analyses and identifying special operating procedures that might be needed;
- Analyzing current day operating conditions; and
- Implementing the Interconnection-wide transmission loading relief ("TLR") procedure or local procedures to mitigate overloads on the transmission system.

NERC policy regarding monitoring requirements for reliability coordinators includes:

- Monitoring the parameters that may have significant impacts within the reliability area and with neighboring reliability areas with respect to:
 - Actual flows versus limits at key facilities (particularly inter-Control Area, inter-Regional and inter-reliability area interfaces). The reliability coordinator will identify the cause of the constraint and coordinate loading relief by requesting appropriate corrective action according to previously established procedures.
 - System frequency and resolution of significant frequency errors, deviations, and real-time trends. The reliability coordinator will monitor system frequency and work with its control areas and neighboring reliability coordinators to identify the source of frequency deviations and real-time trends and aid in the establishment of corrective actions.

The Midwest ISO's responsibilities to inform control area operators and other reliability coordinators of system conditions in one control area that could affect another control area are those required under NERC Policy 9. In general, a reliability coordinator has the responsibility to notify control areas and other reliability coordinators of conditions monitored by the reliability coordinator that may have a reliability impact on other reliability areas.

Some notification requirements are specific and quantitative, such as the requirement to initiate a reliability coordinator hotline conference call when Interconnection frequency error in excess of 0.03 HZ (Eastern Interconnection) is observed for more than twenty minutes. Other notification requirements are dependent upon the judgment of the reliability coordinator, such as if a transmission loading condition or system voltage is deemed critical to bulk system reliability.

The investigation of the August 14 outage is ongoing. An examination of the actions of all involved reliability coordinators will be one aspect of the investigation. The investigation has not yet addressed those issues.

Question 4: In NERC's 2003 summer assessment, "Reliability of the Bulk Electricity Supply in North America," NERC notes the following:

There is a continuing need for the reliability coordinators, transmission planners, and operators to communicate and coordinate their actions to preserve the continued reliability of the ECAR system. It is anticipated that the ECAR transmission system could become constrained as a result of unit unavailability

and/or economic transactions that have historically resulted in large unanticipated power flows within and through ECAR. If these conditions occur again this summer, local operating procedures, as well as the NERC Transmission Loading Relief procedure (TLR), will need to be invoked in order to maintain transmission system security.

- a. What actions, if any, were taken by utilities in the ECAR system to heed this now prescient warning?**
- b. When NERC issues such a warning, what steps are taken to monitor compliance?**

The Regional Councils and their members use the findings in NERC's annual and seasonal assessments, as those organizations deem appropriate. NERC does not monitor "compliance" with these findings and conclusions because those findings and conclusions are not considered mandatory requirements or standards. That said, NERC does conduct roundtable discussions at its regular committee and subcommittee meetings to review potential operating problems as well as recent past operating experiences. NERC also holds special meetings as needed to review operating events and has instituted operating procedures when necessary to deal with special operating situations and to improve coordination.

ECAR has provided the following additional response:

The statements in the NERC 2003 Summer Assessment that are quoted in this question were excerpted from ECAR's 2003 Summer Assessment of Transmission System Performance (Report 03-TSPP-3 dated May 2003). That report was reviewed and endorsed by all of the ECAR companies via the ECAR Coordination Review Committee and was subsequently approved by the ECAR Executive Board. It is standard operating practice in ECAR to invoke local operating procedures, as well as the NERC Interconnection-wide Transmission Loading Relief (TLR) procedure, to maintain transmission system reliability, on an as-needed basis. The statement in the ECAR 03-TSPP-3 Report reaffirmed ECAR's standard operating practices and served to remind ECAR companies of the importance of adhering to these standard operating practices. It is the responsibility of each individual company's management to alert its system operators of such warnings. ECAR does not monitor the specific actions of its members regarding communications on these types of warning to their operating and planning staffs.

If NERC issues a general warning (e.g., an alert about possible terrorist activity), ECAR communicates that general warning to all of the ECAR companies. If NERC issues a specific warning involving a specific entity or situation, ECAR communicates with the specific company and others as appropriate. At present, the Regional Councils monitor compliance with 27 of NERC's operating policies and planning standards. There are no NERC or ECAR policies or standards for monitoring compliance with warnings or other global communications.

Question 5: Please describe the role NERC will play in the US-Canada Task Force inquiry regarding the recent electricity outages. Will NERC be providing technical assistance, sharing data it collects under its own authorities, or providing personnel to directly staff the Task Force.

NERC expects that its work will be a key component in the US-Canada Joint Task Force inquiry regarding the August 14 blackout. NERC and the Department of Energy are now conducting a joint fact-finding investigation. NERC expects Canadian representatives to join that joint fact-finding investigation in the near future. NERC and DOE collaborated on the data request that NERC issued on August 22,

2003. DOE and NERC are jointly developing a data warehouse to manage the data being submitted in response to that request. DOE and NERC co-hosted a meeting of the major entities involved in the outage to help focus the investigation and begin to develop an understanding of the events that led to the outage. DOE and NERC expect to co-host additional such meetings in the future.

Immediately after the outage, NERC began to form an investigative team of technical experts, including members of NERC's staff, representatives of the three Regional Reliability Councils covered by the outages, and volunteers from across the nation. Shortly after the investigation began, representatives of DOE and FERC joined the investigative effort. The investigative team has numbered between 15 and 30 individuals from day to day, and all members of the team, regardless of their affiliation, have worked side by side to help understand and correlate the massive amounts of data that are being received.

NERC also formed a steering committee of highly regarded experts to provide focus and guidance to NERC's investigative efforts. A principal focus of the steering committee is to make sure that all the right questions get asked. The membership and qualifications of NERC's steering committee are shown in Attachment B to these responses.

As of now, NERC has not been asked to provide personnel to directly staff the Task Force. NERC will provide technical assistance as requested by the Task Force.

Question 6: In addition to its coordination with the Task Force, will NERC be conducting a parallel independent investigation of its own? Will NERC issue its own independent report? Will NERC be making independent recommendations, legislative or otherwise, on how to avoid future blackouts?

As a standing procedure, NERC reviews and reports on disturbances that occur on the bulk electric systems in North America. These disturbances include electric service interruptions, voltage reductions, acts of sabotage, unusual occurrences that can affect the reliability of the bulk electric systems, and fuel supply problems. The purpose of these disturbance reviews is to:


- Share the experiences and "lessons learned" from these events
- Determine if NERC's reliability standards adequately address the normal and emergency conditions that can occur on the bulk electric system.
- Suggest ways that the utilities can better apply NERC and regional reliability standards to their operations and planning.

NERC will be conducting an investigation of the August 14 blackout through its standing technical committees, special task groups, and interregional study teams. As the entity responsible for reliability standards for the bulk electric system, NERC must understand what happened on August 14 and why it happened. NERC must also determine whether any of its standards were violated and whether its standards and procedures are sufficient for the ways in which the bulk electric system is being operated. Finally, NERC must assure that measures necessary to avoid a recurrence of the August 14 outage are taken. NERC will make its work available to the Task Force as it becomes available.

The Honorable John Dingell
September 2, 2003
Page Eight

As your letter indicates, I will be a witness before the Committee on Energy and Commerce dealing with this subject on September 3, 2003. I hope these responses will assist the Committee in its deliberations. I look forward to further discussion of these issues at the hearing.

Very truly yours,

A handwritten signature in black ink, appearing to read "Michael R. Gund", with a long horizontal flourish extending to the right.

Policy 9 – Reliability Coordinator Procedures

Version 2

*For implementation
February 15, 2000*

Subsections

- A. Next Day Operations Planning Process
- B. Current Day Operations – Energy
- C. Current Day Operations – Transmission

Introduction

This document contains the process and procedures that the NERC RELIABILITY COORDINATORS are expected to follow to ensure the operational reliability of the INTERCONNECTIONS. These include:

- Planning for next-day operations, including reliability analyses and identifying special operating procedures that might be needed,
- Analyzing current day operating conditions, and
- Implementing the INTERCONNECTION-wide transmission loading relief procedure or local procedures to mitigate overloads on the transmission system.

A. Next Day Operations Planning Process

When disseminating system analysis information, RELIABILITY COORDINATORS are expected to comply with the provisions of NERC's "Confidentiality Agreement for Electric System Reliability." [Appendix 4B]

Requirements

1. **Perform security analysis.** The RELIABILITY COORDINATORS shall ensure that next-day reliability analyses are performed simultaneously for all CONTROL AREAS and TRANSMISSION PROVIDERS in its RELIABILITY AREA to ensure that the bulk power system can be operated in anticipated normal and contingency conditions.
 - 1.1. **Information sharing.** Each CONTROL AREA in the RELIABILITY AREA shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS. This information shall be available by 1200 Central Standard Time for the Eastern INTERCONNECTION, and 1200 Pacific Standard Time for the Western INTERCONNECTION.
 - 1.2. **System Studies.** The RELIABILITY COORDINATORS shall conduct studies to identify potential interface and other OPERATING RELIABILITY LIMIT violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.
2. **Study Results.** The RELIABILITY COORDINATORS shall share the results of their system studies, when conditions warrant, or upon request, with other RELIABILITY COORDINATORS, TRANSMISSION PROVIDERS, and CONTROL AREAS within their RELIABILITY AREA. Study results

Policy 9 – Reliability Authority Procedures

A. Next Day Operations Planning Process

shall be available no later than 1500 Central Standard Time for the Eastern INTERCONNECTION, and 1500 Pacific Standard Time for the Western INTERCONNECTION, unless circumstances warrant otherwise. If the results of these studies indicate potential reliability problems, the RELIABILITY COORDINATORS shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS.) TT

- 3. Conference calls.** Any time that conditions warrant, a conference call or other appropriate communications shall be initiated by any RELIABILITY COORDINATOR to address whatever problems are revealed by the reliability analyses.
- 4. Special operating procedures.** Potential operating procedures that may be required shall be identified, including reconfiguration of the transmission system, redispatching of generation, or reduction or curtailment of INTERCHANGE TRANSACTIONS to maintain transmission loading within acceptable limits. [See Appendix C1, Subsection E, “Principles for Mitigating Constraints On and Off the Contract Path.”]

B. Current Day Operations – Energy

[Appendix B, Subsection A, “Energy Emergency Alerts”]

Requirements

1. **CONTROL AREA generation resource availability analysis.** Each NERC RELIABILITY COORDINATOR shall analyze generation resource availability and reserve levels for the CONTROL AREAS, RESERVE-SHARING GROUPS, and LOAD-SERVING ENTITIES in his RELIABILITY AREA to determine any actual or potential energy deficiencies.
2. **Authority to provide emergency assistance.** Each RELIABILITY COORDINATOR must have the authority to take or direct whatever action is needed to mitigate an energy emergency within his RELIABILITY AREA.
3. **Notification.** Each RELIABILITY COORDINATOR that is experiencing a potential or actual energy emergency within any CONTROL AREA, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within his RELIABILITY AREA may initiate an ENERGY EMERGENCY ALERT as detailed in **Appendix B, Subsection A – “Energy Emergency Alert Levels.”**
4. **INTERCONNECTION FREQUENCY ERROR.** Any RELIABILITY COORDINATOR noticing an INTERCONNECTION FREQUENCY ERROR in excess of 0.03 Hz (Eastern INTERCONNECTION) or 0.05 Hz (Western and ERCOT INTERCONNECTIONS) for more than 20 minutes shall initiate a RELIABILITY COORDINATOR Hotline conference call, or notification via the RCIS, to determine the CONTROL AREA(S) with the energy emergency or control problem.

C. Current Day Operations – Transmission

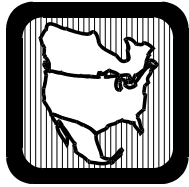
[Policy 3A, “Interchange – Interchange Transaction Implementation”]
[Appendixes 9C1, 9C2, 9C3, “Transmission Loading Relief Procedures”]

Requirements

1. **Interchange Transaction information.** The RELIABILITY COORDINATOR shall ensure that information on all INTERCHANGE TRANSACTIONS is available to all RELIABILITY COORDINATORS in the INTERCONNECTION.
 - 1.1. **Interchange Distribution Calculator.** All INTERCHANGE TRANSACTIONS whose SOURCE CONTROL AREA or SINK CONTROL AREA, or both, are in the EASTERN INTERCONNECTION must be entered into the Interchange Distribution Calculator (IDC). [See also Appendix 3A2, “Tagging Across Control Area Boundaries.”]
 - 1.1.1. **Responsibility.** The RELIABILITY COORDINATOR for the SINK CONTROL AREA shall periodically audit the IDC to ensure that the INTERCHANGE TRANSACTION tags have been entered into the INTERCHANGE DISTRIBUTION CALCULATOR.
2. **Notify RELIABILITY COORDINATORS of potential problems.** The RELIABILITY COORDINATOR who foresees a transmission problem within his RELIABILITY AREA shall issue an alert to all CONTROL AREAS and Transmission Providers in his RELIABILITY AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the RCIS without delay.
3. **Implementing relief procedures.** If transmission loading progresses or is projected to progress beyond the OPERATING RELIABILITY LIMIT, the RELIABILITY COORDINATOR will perform the following procedures as necessary:
 - 3.1. **Manage INTERCHANGE TRANSACTIONS.** The RELIABILITY COORDINATORS will continue to manage INTERCHANGE TRANSACTIONS through their respective CONTROL AREAS during this period to help mitigate the OPERATING RELIABILITY LIMIT violation.
 - 3.2. **Selecting transmission loading relief procedure.** The RELIABILITY COORDINATOR experiencing a constraint on a transmission system within his RELIABILITY AREA shall, at his discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure, such as those listed in Appendix C1, C2, or C3.
 - 3.2.1. **Local transmission loading relief procedure.** The RELIABILITY COORDINATOR may use local transmission loading relief or congestion management procedures, provided the transmission system experiencing the constraint is a party to those procedures.

- 3.2.1.1. Use with an INTERCONNECTION-wide Procedure.** A RELIABILITY COORDINATOR may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, he is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY COORDINATOR desires to use a local procedure as a substitute for curtailments as directed by the INTERCONNECTION-wide procedure, he may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.¹
- 3.2.1.2. IDC Update.** The RELIABILITY COORDINATOR must enter, or have entered on his behalf, into the IDC all INTERCHANGE TRANSACTION changes that result from the implementation of the local procedure. ***[Eastern Interconnection Requirement]***
- 3.2.2. INTERCONNECTION-wide loading relief procedure.** The RELIABILITY COORDINATOR may implement an INTERCONNECTION-wide procedure as detailed in Appendixes 9C1, 9C2, or 9C3.
- 3.2.2.1. Obligations.** When implemented, all RELIABILITY COORDINATORS shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.
- 3.3. Compliance with Interchange Policies.** During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY COORDINATORS and CONTROL AREAS shall comply with the Requirements of Policy 3, “Interchange.”
- 4. Implementing emergency procedures.** If the transmission loading condition is deemed critical to bulk system reliability by a RELIABILITY COORDINATOR, the RELIABILITY COORDINATOR has the authority to immediately direct the CONTROL AREAS in his RELIABILITY AREA to redispatch generation, reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing a transmission loading relief procedure, or other procedures, to return the system to a reliable state. The RELIABILITY COORDINATOR shall coordinate these emergency procedures with other RELIABILITY COORDINATORS as appropriate. All CONTROL AREAS shall comply with all requests from their RELIABILITY COORDINATOR as authorized by the Regional Reliability Plan.
- 5. Reestablishing INTERCHANGE TRANSACTIONS.** The RELIABILITY COORDINATOR shall coordinate with the CONTROL AREAS in his RELIABILITY AREA, and with other RELIABILITY COORDINATORS as appropriate, the reestablishment of the INTERCHANGE TRANSACTIONS that were curtailed. The reestablishment of these INTERCHANGE TRANSACTIONS and the resulting INTERCHANGE SCHEDULES shall be in compliance with **Policy 3, “Interchange.”**

¹ Examples would be 1) a local procedure that curtails INTERCHANGE TRANSACTIONS in a different order or ratio than the INTERCONNECTION-wide procedure, or 2) a local redispatch procedure.



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

August 14, 2003 Blackout Investigation NERC Steering Group

SCOPE August 27, 2003

Scope

The NERC Steering Group steers the formulation and implementation of the NERC blackout investigation plan, reviews the milestone progress and results, and recommends improvements. The Steering Group provides a perspective of industry experts in power system planning, design, and operation.

Members

The members of the NERC Steering Group are:

Paul F. Barber, Facilitator
Barber Energy

Yakout Mansour
Senior Vice President
System Operations & Asset Management
British Columbia Transmission Corporation

W. Terry Boston
Executive Vice President
Transmission/Power Supply Group
Tennessee Valley Authority

William (Bill) K. Newman
Senior Vice President
Transmission Planning and Operations
Southern Company Services, Inc.

Mark Fidrych
Power Operations Specialist
Western Area Power Administration

Terry M. Winter
President and Chief Executive Officer
California ISO

Sam R. Jones
Chief Operating Officer
Electric Reliability Council of Texas

M. Dale McMaster
Executive Vice President—Operations and
Reliability
Alberta Electric System Operator

Biographies

Paul F. Barber, Ph.D.

Barber Energy

Dr. Barber provides transmission and engineering services to the electric power industry in areas of governance, strategic planning, electric grid management, and power system reliability. He previously served as the Chair of the NERC Market Interface Committee and as the Vice Chair (Transmission Customers) of the Northeast Power Coordinating Council (NPCC). Dr. Barber joined Boston-based Citizens Power & Light, providing transmission and engineering technical expertise and support to all business lines of Citizens Power & Light and its successors. Dr. Barber served on the NERC Board of Trustees as well as the Boards of the Mid-Atlantic Area Council, Western Systems Coordinating Council (WSCC), and the three Regional Transmission Associations in the Western Interconnection. Prior to 1994, Dr. Barber served a 28-year career as an officer in the U.S. Army Corps of Engineers rising to the rank of Colonel. Dr. Barber received his BS degree from the U.S. Military Academy and MS degrees in electrical engineering and civil engineering from the University of Illinois. He completed a Ph.D. degree in electric power engineering from Rensselaer Polytechnic Institute in 1988. He has been registered in the State of Illinois as a professional engineer since 1974.

W. Terry Boston

Executive Vice President, Transmission/Power Supply Group

Tennessee Valley Authority

Terry Boston is Executive Vice President of the Tennessee Valley Authority's Transmission/Power Supply Group. Mr. Boston is the senior officer responsible for the planning, building, operation, and maintenance of TVA's transmission and power supply network. He joined TVA as a power supply engineer in 1972, and was named head of the Power Supply Group in 1980. Over the next 16 years, he directed three TVA divisions in succession: Transmission, Regional Operations, and Electric System Reliability. Mr. Boston has served for six years on the NERC Engineering Committee and Transmission Task Force, and is on the NERC Stakeholders Committee. He is vice president of CIGRE, the International Council on Large Electric Systems, and vice president of CERTS (the Consortium for Electric Reliability Technology Solutions). Boston holds a B.S. in engineering from Tennessee Technological University and an M.S. in engineering administration from the University of Tennessee.

Mark Fidrych

Power Operations Specialist

Western Area Power Administration

Mark E. Fidrych has served as the Manager of Western Area Power Administration's Rocky Mountain Desert Southwest Reliability Center. Mr. Fidrych began his career with WAPA in 1979, working in maintenance and marketing, with the majority of his career having been in power system operations. He directed activities in the computer systems and power scheduling divisions before becoming the Operations Manager in 1990. A 1972 graduate of the University of Rhode Island, Mr. Fidrych received a bachelor's degree in electrical engineering. In 1980, he received a master's degree in public administration from the University of Colorado. Mr. Fidrych is the present Chair of the NERC Operating Committee. He has also served as the Chair of the NERC Security Coordinator and the Operating Reliability Subcommittees.

Sam R. Jones

Chief Operating Officer

Electric Reliability Council of Texas

Sam R. Jones became the first Director of the Electric Reliability Council of Texas (ERCOT) on December 1, 1996. In March 2000, he was appointed as the Executive Vice President and Chief Operating Officer of ERCOT. Prior to joining ERCOT, Mr. Jones was employed by the City of Austin, Texas, Electric Utility for over 35 years. With the City of Austin, he held engineering and management positions in the areas of distribution, transmission, substation, generation and system operations. He was responsible for the development of Austin's first energy control center. He retired from the City of Austin as Director of Generation and Energy Control. He has been active in inter-utility reliability work for over 19 years. He is a two-time past chair of the ERCOT Operating Subcommittee, and a current Vice-Chair of the NERC Operating Committee, and a past chair (or member) of numerous NERC and ERCOT subcommittees and task forces. Mr. Jones has a degree in Electrical Engineering from the University of Texas at Austin and is a Registered Professional Engineer in Texas.

Yakout Mansour
Senior Vice President, System Operations & Asset Management
British Columbia Transmission Corporation

Yakout Mansour is Senior Vice President of System Operations & Asset Management of the British Columbia Transmission Corporation. Previously, he served as the Vice President of the Grid Operations and Inter-Utility Affairs division of BC Hydro, responsible for BC Hydro's transmission, distribution and generation dispatch operations as well as the development of policies and practices related to inter-utility transmission access. Mr. Mansour currently serves as BC Hydro's principal representative and board member on the RTO West filing utilities structure and has been the Canadian representative in the RTO consultation process. Mr. Mansour is a registered Professional Engineer in the Provinces of British Columbia and Alberta with over 30 years experience in power system planning, system and market operation, design and research. He is a Fellow of IEEE, has authored and co-authored over 100 papers and special publications of IEEE and other international professional institutions, has provided training and consulting services around the world, and holds U.S. and Canadian patents.

Dale McMaster, P.Eng.
Executive Vice-President, Operations and Reliability
Alberta Electric System Operator (AESO)

Dale McMaster is Executive Vice-President, Operations and Reliability for the Alberta Electric System Operator (AESO). The AESO integrates the functions of the Power Pool of Alberta, the Transmission Administrator of Alberta, and provincial load settlement. Mr. McMaster's knowledge of system planning and his overall industry experience integrates the AESO's operational and planning areas. As President and System Controller, Mr. McMaster played a key role during the integration of the former Power Pool and the Transmission Administration. Mr. McMaster joined the former Power Pool of Alberta in 1996 as Chief Operations Officer, with responsibility for the system control function, the ongoing development of the Alberta electric energy market, and strategic planning. He is an electrical engineer with more than 25 years of experience in power systems in Canada and abroad. Mr. McMaster received his degree in electrical engineering from the University of Saskatchewan and held a variety of senior management positions at SaskPower, SNC-Lavalin, and Acres International. He is a member of the Association of Professional Engineers, and the Canadian Electricity Association.

William K. Newman
Senior Vice President, Transmission Planning & Operations
Southern Company

William K. Newman began his career with Georgia Power Company in 1966 and progressed through positions of increasing responsibility at Georgia Power for 18 years. In 1984, he assumed the position of General Manager, Power Operations, at Mississippi Power Company, was promoted to Director of Power Delivery in 1988 and named Vice President, Power Generation and Delivery, in 1989. His responsibilities at Mississippi Power Company included the areas of fuels, environmental, generating plants, transmission, and system operations. He transferred to Southern Company Services in 1992 as Vice President, Operating and Planning Services and was named Senior Vice President, Transmission Planning and Operations in 1995. He is responsible for planning and operation of the Southern electric system's network transmission grid in order to provide economic, reliable service to all users. Mr. Newman has served in numerous academic and professional organizations and is currently Chairman, Southeastern Electric Reliability Council. He is a Registered Professional Engineer in the states of Georgia and Mississippi.

Terry M. Winter,
President and Chief Executive Officer
California ISO

Terry M. Winter is President and Chief Executive Officer of the California Independent System Operator (ISO), a position he has held since March 1, 1999. Mr. Winter was formerly Chief Operating Officer of the California ISO, having accepted the position in August 1997. He assisted in developing operations from the ground up and oversaw the integration of the transmission systems of Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric when the California ISO assumed control of the state's open market transmission grid on March 31, 1998. Mr. Winter was formerly the Division Manager of San Diego Gas & Electric's power operations. His 21-year career with SDG&E focused on power operations, transmission engineering and project management. Prior to his tenure with SDG&E he worked on electrical transmission and distribution engineering for Arizona's Salt River Project for 10 years. Mr. Winter holds professional engineering licenses in both California and Arizona. Mr. Winter graduated from the University of Idaho with a Bachelor of Science degree in Electrical Engineering.